3.0 IVSG Transmission Studies

The conceptual development plan recommended by the IVSG is based on ten months of detailed transmission studies. These studies provide the basis for the development plan. This chapter describes the alternatives selected for evaluation, and the process used to study them.

3.1 Selection of Initial Export Path Study Alternatives

The IVSG was charged with identifying transmission solutions capable of exporting 2,200 MW of new renewable resources from the Imperial Valley. IID, SDG&E, CalEnergy and CEERT first developed an initial list of export paths for study, consistent with this requirement: all alternatives had to be capable of delivering the full 2,200 MW. Other initial considerations were planned upgrades to the southwest regional grid being pursued through STEP; IID's plans to upgrade its own transmission system in order to support larger exports of renewable power from its control area and reinforce its system reliability; CalEnergy's development schedule for new geothermal generating units at the Salton Sea; and SDG&E's reliability-driven need for new EHV transmission by 2010 and its on-going Transmission Comparison Study.

Both 230 kV and 500 kV solutions were considered as study alternatives; upgrades at lower voltages were judged impractical for such a large-scale development. Upgrade of Path 45 through Mexico was considered; this would potentially enable flows from the Imperial Valley to Miguel, via Mexicali and Tijuana. This was abandoned because it would worsen the already-intractable transmission bottlenecks at the Imperial Valley and Miguel substations; would require ~80 miles of new transmission construction/new ROW through mountainous terrain in Baja Norte; and would involve US-Mexico treaty negotiations and export licensing for flows from Mexico into California.

At its first meeting in November 2004, the IVSG discussed and unanimously adopted seven transmission alternatives for study, based on a list of routings suggested by IID, SDG&E and CalEnergy. Upgrades of the IID system were common to all the alternatives. The fact that the IID system extends around much of Imperial County makes it possible for renewable resources, including wind and solar, to connect in many locations, at workable voltages. The upgraded IID network would also directly access all KGRAs in the county. The key components of each alternative were:

1. **Alternative 1**: Imperial Valley (IV) substation to a new San Diego Central substation, at 230 kV; a new 230 kV connection from the IID Bannister substation to the proposed 230 kV, IV-SD Central line; and upgrades to the IID system (Midway–Parker; Midway-Highline; El Centro-Highline; El Centro-IV; Blythe-Knob; Knob-Pilot Knob).

2. **Alternative 2**: same as Alt 1, but with Imperial Valley substation to a new San Diego Central substation, at 500 kV.

3. **Alternative 3a**: same as Alt 2, but with a 500 kV connection from IV to a new San Diego North substation (instead of a San Diego Central substation location).

4. **Alternative 3b**: same as Alt 3a, but with a connection to the SCE system from a new San Diego North substation across the Lake Elsinore Advanced Pumped Storage Project (LEAPS) route.

5. **Alternative 4a**: North Gila to Imperial Valley (IV) substation to a new San Diego Central substation, at 500 kV; plus all IID system upgrades.

6. **Alternative 4b**: same as Alt 4a, but with the proposed IID/APS Palo Verde-Yuma project added.

7. **Alternative 5**: same as Alt 2 (500 kV line, IV-SD Central), but with an additional 500 kV connection from the Imperial Valley substation north to the Palo-Verde-Devers #1 line, at a new Indian Hills substation; and a 230 kV connection from the IID Coachella Valley substation to the new Indian Hills substation.

Figure 3.1 Study Alternative 1

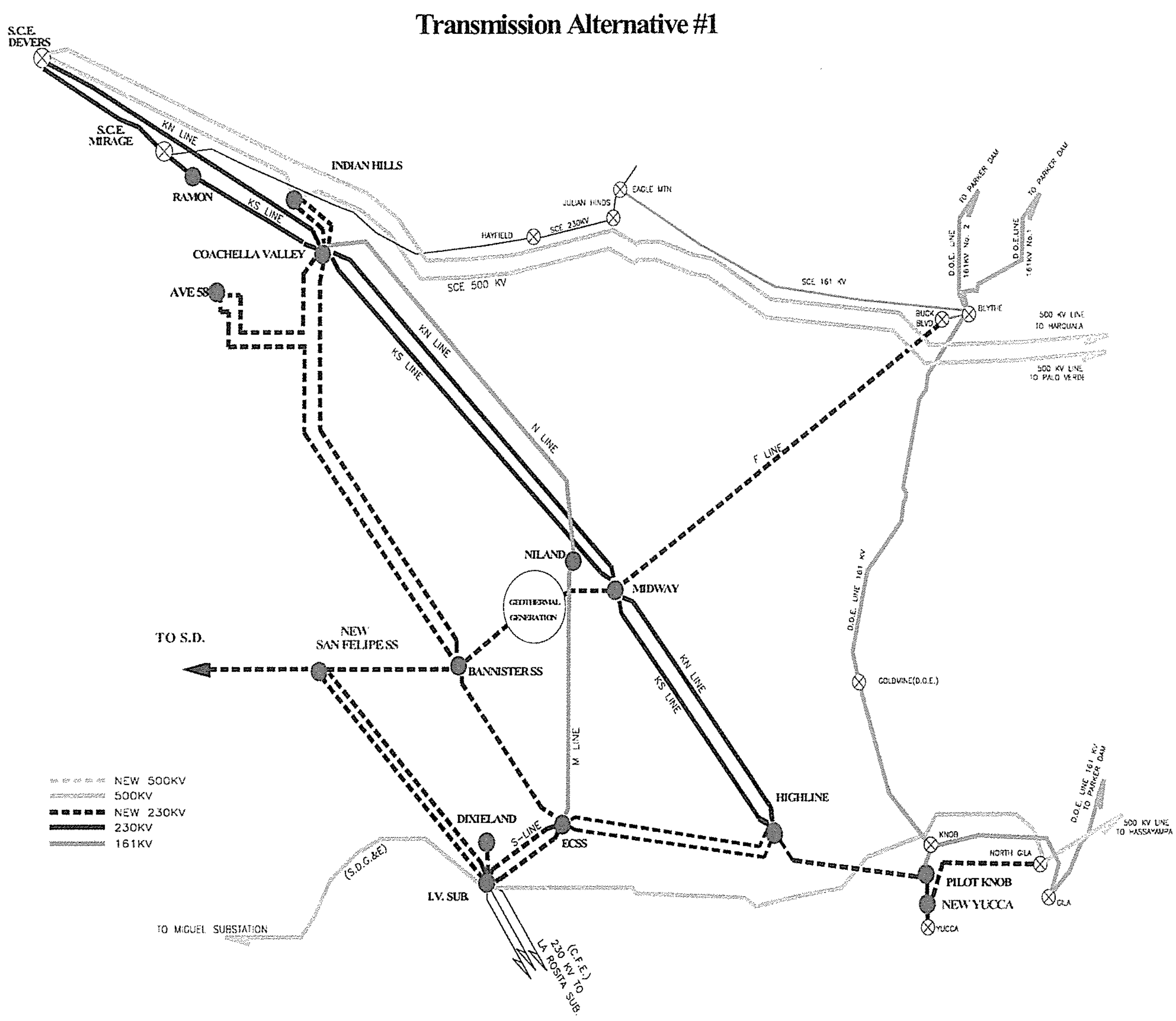


Figure 3.2 Study Alternative 2

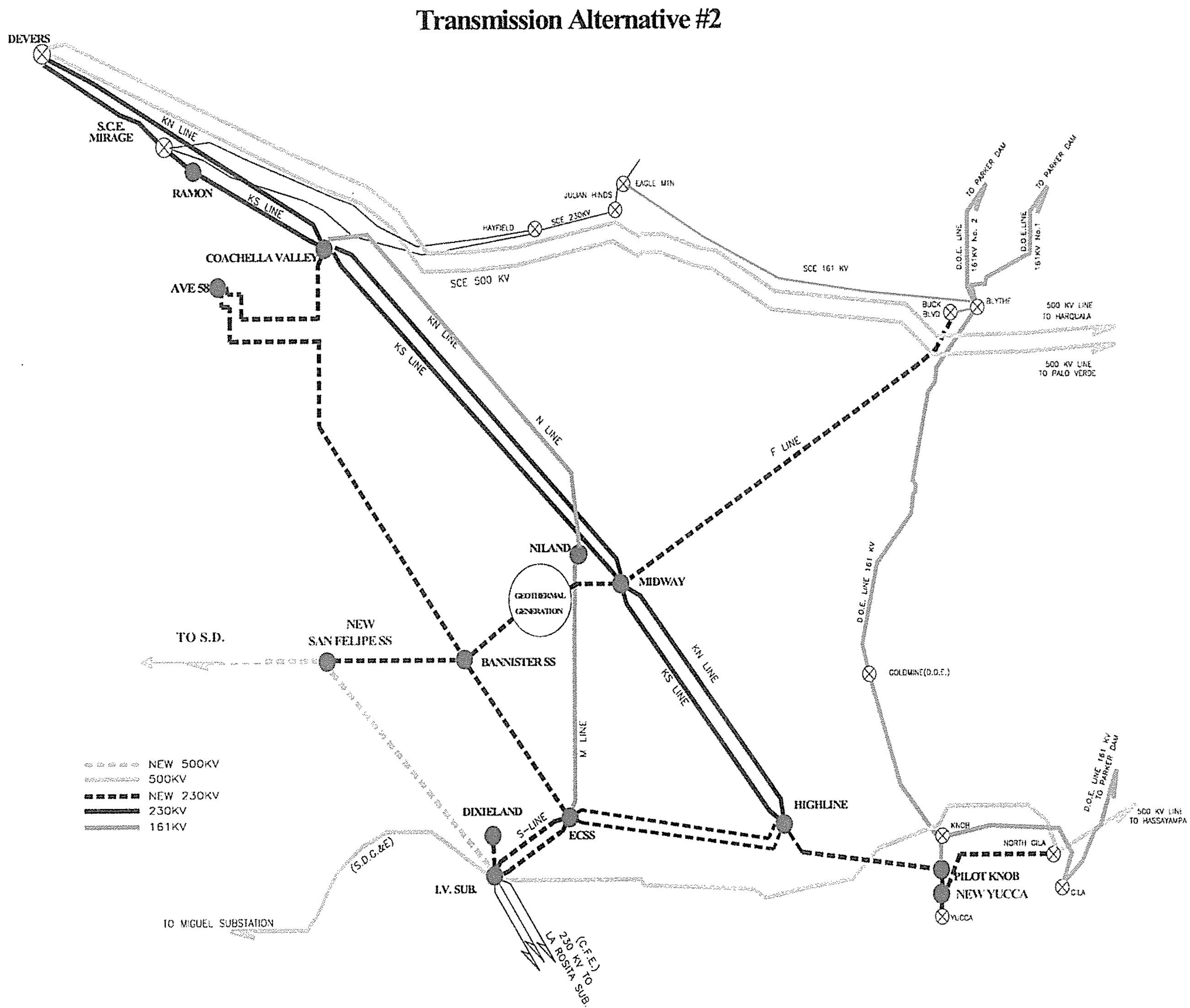


Figure 3.3 Study Alternative 3a

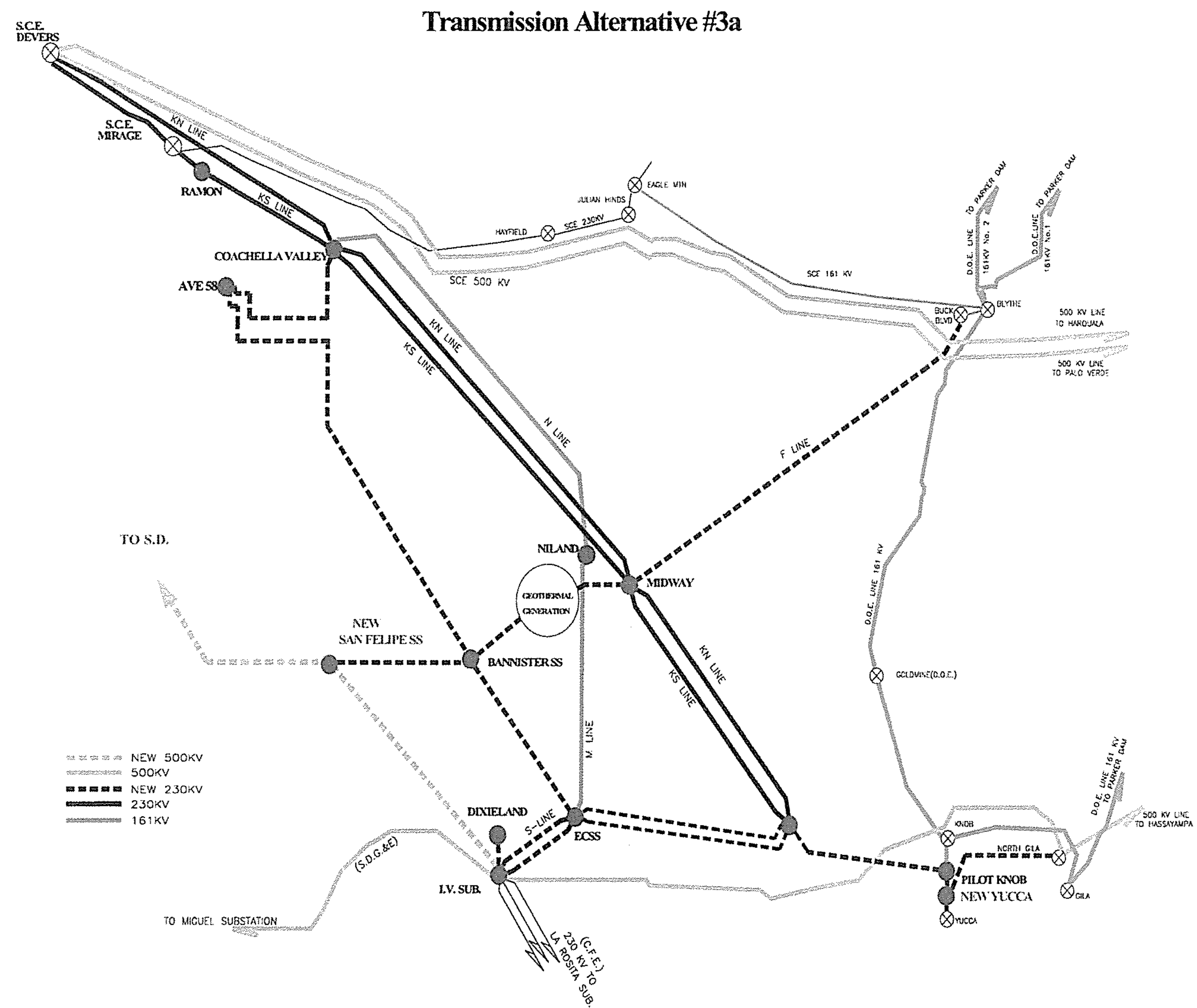


Figure 3.4 Study Alternative 3b

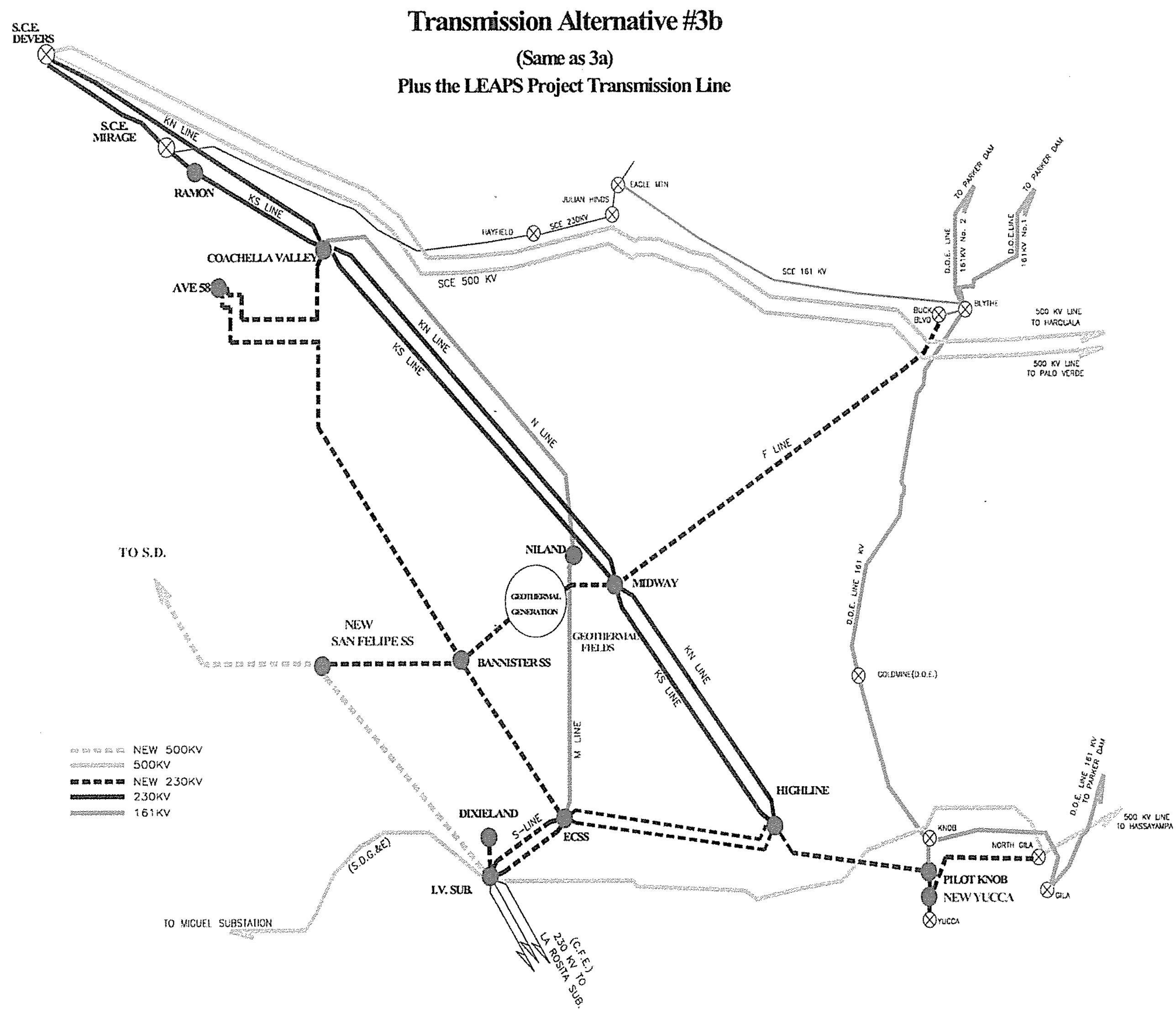


Figure 3.5 Study Alternative 4a

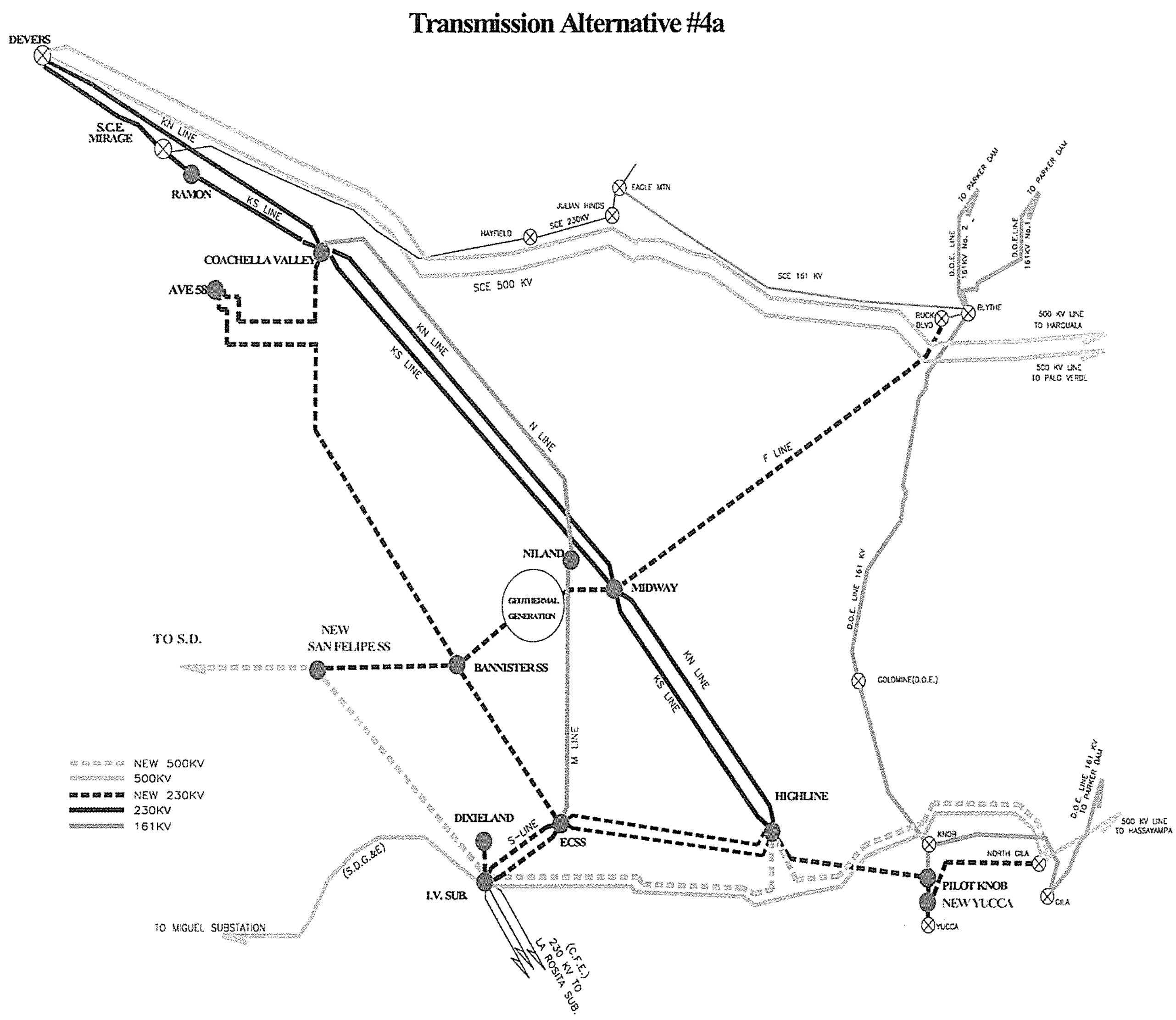


Figure 3.6 Study Alternative 4b

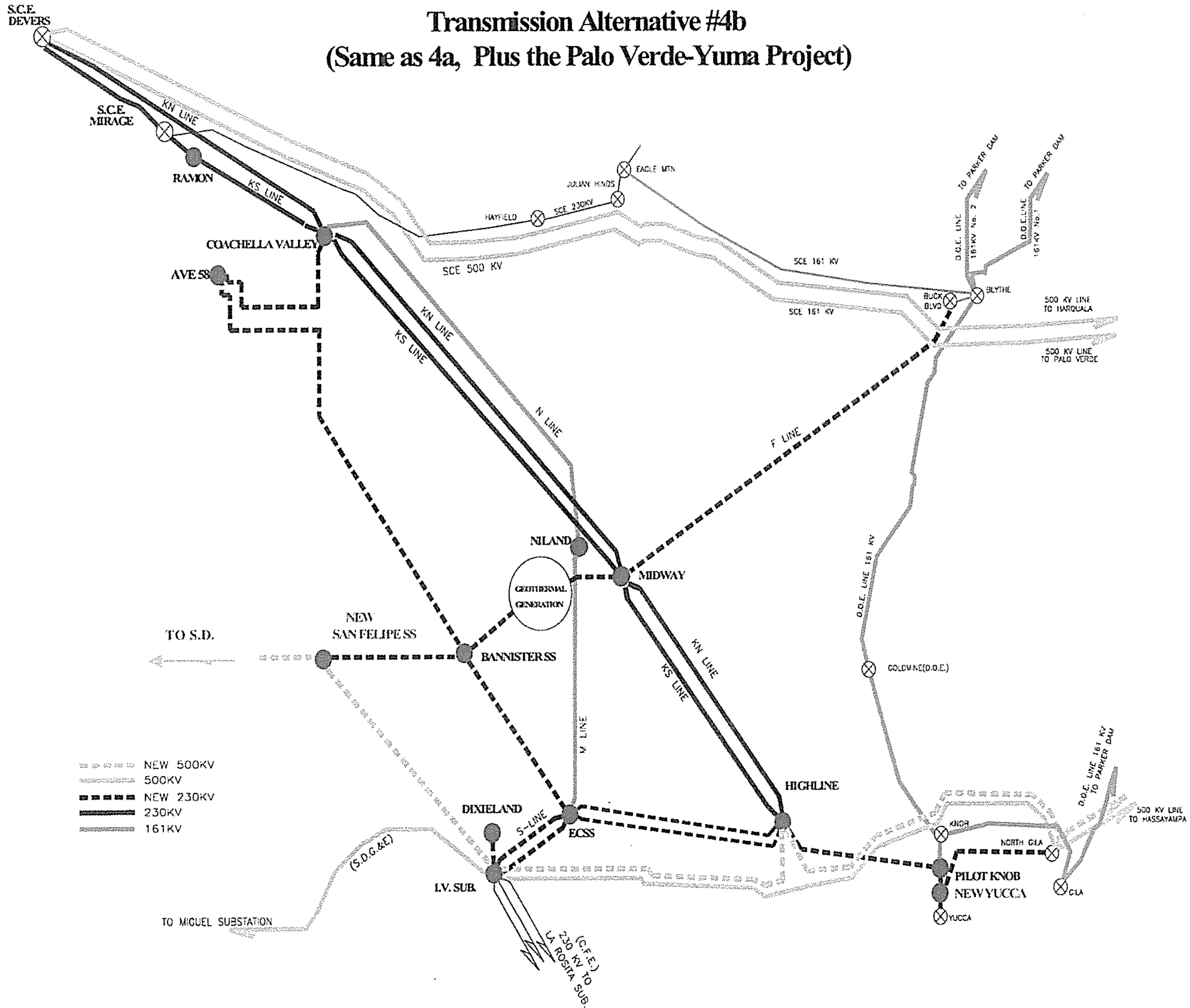
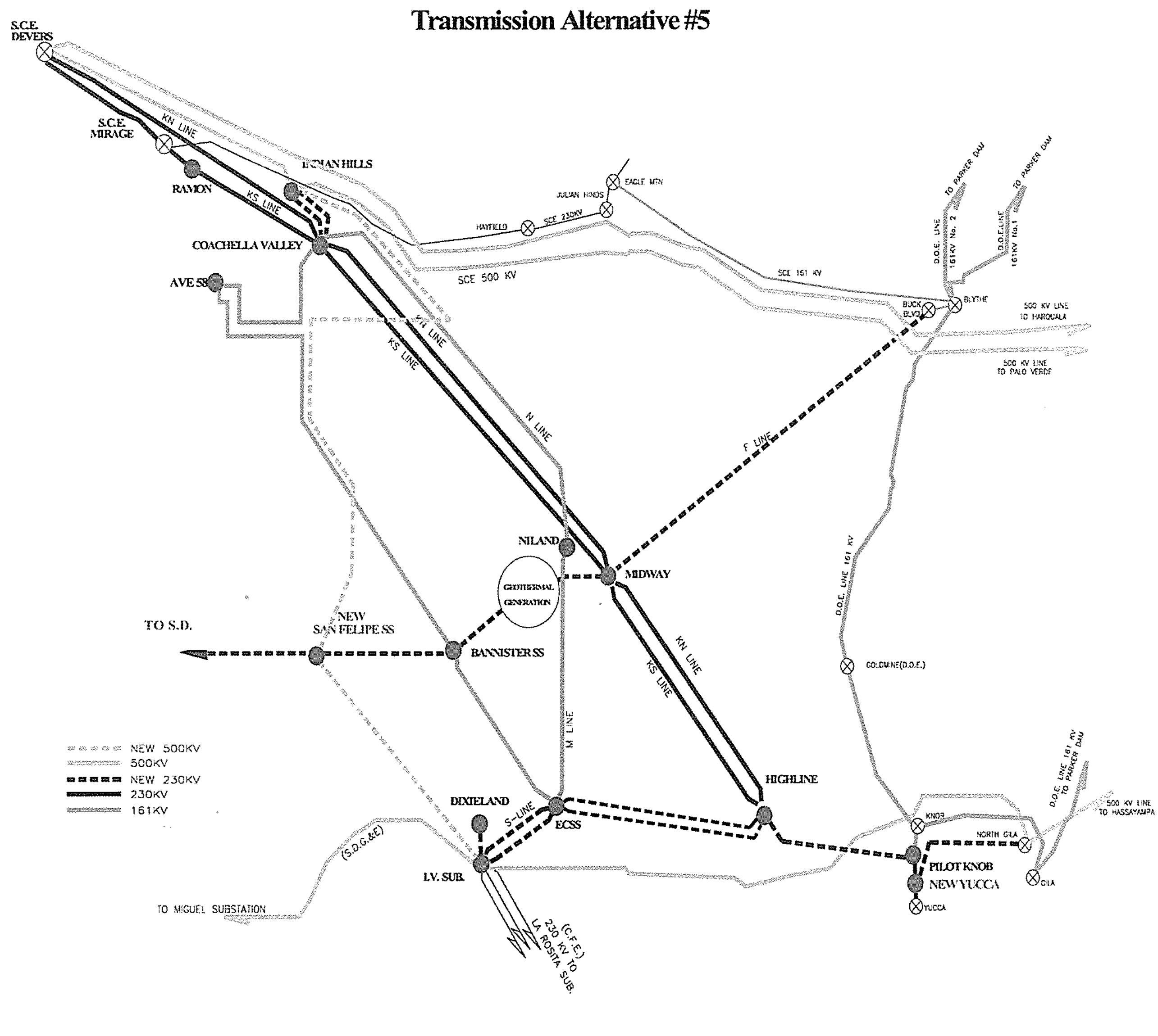


Figure 3.7 Study Alternative 5



3.2 Power Flow Studies

All IVSG power flow studies have been conducted using PSLF version 13.1. The IVSG Technical Work Group (TWG) first constructed base cases to represent the flows on the regional transmission system before adding any incremental Imperial Valley generation or any transmission upgrades, for Heavy Summer (maximum flows) and for Light Autumn (minimum flow conditions). It adopted a forecast of loads and resources for 2014, agreed on contingencies to consider, and developed a dispatch schedule to explore the export of Imperial Valley generation to different power customers. It then ran the 2014 Heavy Summer and Light Autumn cases with increments of new Imperial Valley generation added against the base cases, to evaluate the impacts and the upgrades needed.

Standard power flow planning criteria were employed.[9] Loading criteria were based on the normal or continuous rating (Rating 1) as identified in the cases.

3.2.1 Development of Base Cases

The IVSG chose 2014 as its study year, for two reasons: it could represent a plausible midpoint in the contemplated 2,200 MW generation-transmission development; and there was a WECC-approved Heavy Summer case for that planning year. There was, however, no WECC-approved Light Autumn base case for 2014. Instead, the TWG began with the WECC-approved 2009 Light Autumn case, and modified it to represent 2014 loads and resources.

The CAISO supplied an initial dataset of 2014 loads, resources and flows, for both Heavy Summer and Light Autumn periods. Each TWG Transmission Owner modified/updated this pre-project model in turn, to ensure that the loads, resources and flows on its system were accurately represented. This was essential, as the ISO does not have data on the IID, WAPA or CFE systems.

Imperial Valley area geothermal plants operating today were included as existing generation in the base cases. These include 80 MW at the Heber KGRA; 90 MW operated by Ormesa, also at Heber; 60 MW recently acquired by Ormat from Covanta; and 310 MW at the Salton Sea KGRA operated by CalEnergy. These existing facilities total over 500 MW of resources scheduled to SCE. The base cases also include Salton Sea Unit 6, a 215 MW geothermal plant whose output IID has contracted to buy from CalEnergy. The base cases include the STEP Short-Term

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[9] These criteria include:

- Pre-disturbance bus voltage must be between 0.95 per unit and 1.05 per unit.
- Allowable voltage deviation of five (5) percent for N-1 Contingencies (deviation from pre-disturbance voltage).
- Allowable voltage deviation of ten (10) percent for N-2 contingencies (deviation from pre disturbance voltage).
- Post transient bus voltage must be at least 0.90 per unit.
- Pre and post disturbance loading to remain within the emergency ratings of all equipment and line conductors. The emergency ratings are determined by the owner/operator of each equipment item.

Upgrades (i.e., Path 49 is modeled with a 8,055 MW path rating), and a new Vincent-Mira Loma 500 kV line added in the LA Basin. The Devers-Palo Verde 2 line is included, and is modeled as on-line in all cases.

3.2.2 Dispatch Scenarios

The study used CAISO Generation Retirement assumptions, to identify units on the ISO grid likely not to be running in 2014. Consistent with ISO planning criteria, new geothermal/renewable generation, which has very low marginal cost, was assumed to displace higher cost generation around the region. Generating units assumed to be displaced are listed in the "Offset" column in Appendix A.2, Dispatch Scenarios.

The TWG developed different dispatch scenarios for each of the Heavy Summer and Light Autumn cases. These were designed to stress the regional transmission system under maximum and minimum flow conditions, in order to evaluate worst-case possibilities. The dispatch scenarios were also selected to represent likely or possible sales of power from Imperial Valley resources. The dispatch scenarios are listed in Table 3.1 below.

Table 3.1 Dispatch Scenarios

AREA	D1 (HS) Dispatch	D2 (HS) Dispatch	D3 (LA) Dispatch	D4 (LA) Dispatch
IID	200	200	200	200
SDGE	1000	200	200	400
SCE	400	300	1000	600
LADWP	200	200	200	200
PG&E	400	600	0	800
WAPA	0	100	100	0
ARIZONA	0	500	500	0
NPC	0	100	0	0
Total	2,200	2,200	2,200	2,200

3.2.3 Contingencies

Transmission Owners ("TO") each provided a transmission element outage list covering key facilities on their systems. These were compiled to form a master contingency list. This contingency list included N-1 (one single transmission component out of service) and N-2 contingencies (two transmission components out of service). The list also included transmission component forced outage to model events such as a circuit breaker failing to open. This master contingency list was run in each study to evaluate system reliability, feasibility and impact.

3.2.4 Heavy Summer Cases

The initial power flow modeling included 14 runs for the Heavy Summer cases (seven alternatives for each of the two dispatch scenarios shown on Table 3.1). Key findings of the Heavy Summer runs included:

- The IID 230 kV and 500 kV alternatives were found to be effective (no overloads within the IID controlled network) at delivering 2,200 MW of new resources out of the IID controlled network.

- The Salton Sea area collector system developed for this analysis is adequate to deliver approximately 2,000 MW of geothermal resources (the full potential of the Salton Sea KGRA) to the Midway and Bannister 230 kV substations.

- Of the new alternatives, the 500 kV alternatives provided a higher level of deliverability to the regional system when compared to the 230 kV alternatives. However, depending on the magnitude of the new resources developed, initial deliveries can be made via 230 kV system (e.g. new facilities constructed at 500 kV but operated initially at 230 kV). Also note that only approximately 30 miles of new ROW is required for all of the alternatives.

- Delivery constraints were noted at Miguel, Sycamore, Mirage, and Valley substations. Additional review of delivering the new resources beyond these facilities will be required by SDGE and SCE.

- The Imperial Valley – Miguel 500 kV line outage was found to be the most severe outage impacting the regional system with 2,200 MW of additional resources added within the IID transmission system.

- The Bannister – San Felipe, and Bannister – El Centro – Imperial Valley – San Felipe loop provides for added reliability of delivering higher amounts of geothermal resources to the SDG&E area loads (either at San Diego Central or San Diego North) under contingency conditions.

- The upgrades on Path 42 (both Coachella to Devers 230 kV lines) and an interconnection to the Palo Verde–Devers 500 kV line provides for added reliability of delivering higher amounts of renewable resources to the SCE area loads under contingency conditions. However, the impact on the west of Devers system was not comprehensively evaluated.

3.2.5 Selection of Final Study Alternatives

The results of the Heavy Summer cases showed that all of the initial alternatives were able to export 2,200 MW from the IID system. Some of the alternatives performed better than others, and some were found to be unnecessary for the export of 2,200 MW. This thermal analysis led the TWG to eliminate some of the alternatives from further study:

Alternative 1 was dropped, because it did not meet objectives for reliability, access to renewable resources and low overall transmission costs as well as any of the 500 kV alternatives.

Alternative 3a was eliminated because it did perform as well as Alternative 3b, which provided a connection between the SDG&E and SCE systems and thus supported regional flows back to the east.

Alternative 4a was dropped because the connection to North Gila was found to be unnecessary for the export of new generation from the Imperial Valley.

Alternative 4b was eliminated because a second 500 kV connection was found to be unnecessary for the export of 2,200 MW, and because Alternatives 2 and 3 offered better electrical performance.

Alternative 5 was also dropped because a second 500 kV connection was found to be unnecessary.

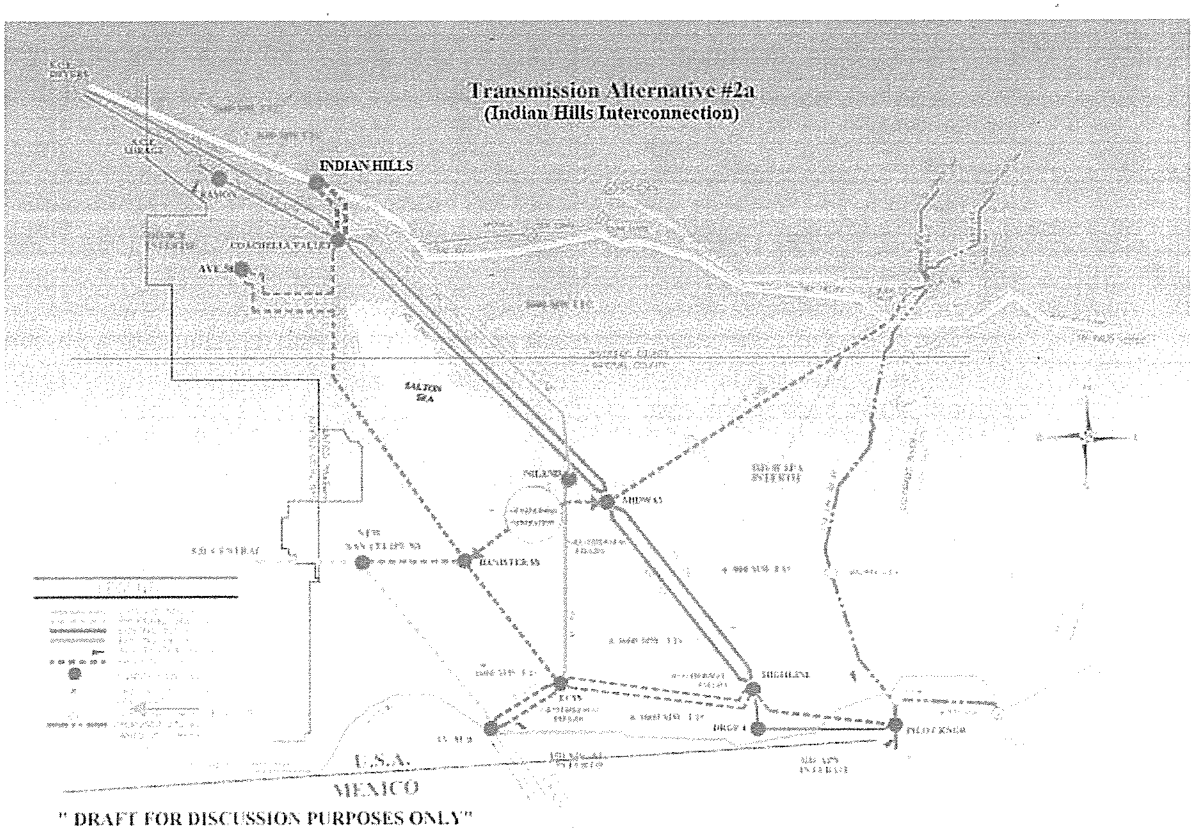
Two of the original alternatives were selected for further evaluation based on the results of this screening analysis, and a variant on Alternative 2 was added:

1. Alternative 2: A new 500 kV line from Imperial Valley to San Diego Central, with 50 percent series compensation added to the San Felipe-to-San Diego Central portion of the line. Alt 2 is outlined in Figure 3.2.
2. Alternative 2a: This variant on Alt 2 was added to evaluate the effect of adding a new 230 kV tie between IID and the CAISO at a new Indian Hills substation on the Devers-Palo Verde 1 line. It is the same as Alternative 2 except for this tie. A diagram of Alt 2a is included in Figure 3.8 below.
3. Alternative 3b: A new 500 kV Imperial Valley to San Diego North to (SCE) Serrano-Valley transmission line, with 50 percent series compensation added to the San Felipe-to-San Diego North portion of the line.[10] Figure 3.4 shows Alt 3b.

Power flow studies were then performed on these three alternatives under Light Autumn load conditions. Stability studies and post-transient studies were later performed on these alternatives as well.

[10] SDG&E determined in August 2005 that the best routing for a 500 kV connection to its system from the east would extend to a San Diego-Central substation, rather than to a San Diego-North location (as studied by the IVSG in its Alternative 3b).

Figure 3.8 Alternative 2a



3.2.6 Light Autumn Cases

Additional power flow studies were performed for Alternatives 2, 2a and 3b under Light Autumn load conditions. The TWG developed two additional dispatch scenarios, as shown on Table 3.1, in order to stress the regional transmission system under Light Autumn load conditions. Six cases were studied (the three Alternatives, for each of two dispatch scenarios). Key findings of the Light Autumn runs included:

- The IID transmission system alternatives were found to be effective (no overloads within the IID controlled network) at delivering 2,200 MW of new resources out of the IID controlled network.

- The Salton Sea area collector system developed for this analysis is adequate to deliver approximately 2,000 MW of geothermal resources (from the Salton Sea KGRA) to the Midway and Bannister 230kV substations.

- Delivery constraints were noted at Miguel, Sycamore, Mirage, and Valley substations. Additional review of delivering the new resources beyond these facilities will be required by SDG&E and SCE.

- The Imperial Valley – Miguel 500 kV and Devers – Valley 500 kV line outages were found to be the most severe outages impacting the regional system with 2,200 MW of additional resources added within the IID transmission system.

- The upgrades on Path 42 (both Coachella to Devers 230 kV lines) and an interconnection to the Palo Verde – Devers 500 kV line provides for added reliability of delivering higher amounts of geothermal resources to the SCE area loads under contingency conditions.

Taken together, these power flow studies enabled the IVSG to develop a thorough understanding of the impact of adding 2,200 MW of new Imperial Valley generation on the flows at major regional buses. These flows are summarized in the table in Appendix A.1.

3.3 Stability Studies

Transient stability studies were conducted to test the alternatives under faulted conditions and system response to the faults with the additional resources connected to the system. The transient stability analysis was conducted on cases for both Heavy Summer and Light Autumn. For the Heavy Summer, stability analysis was conducted on Alternative 2 and Alternative 3b. For the Light Autumn, stability analysis was conducted on Alternatives 2 and 2a (with the interconnection to Indian Hills) and Alternative 3b.

The additional 2,200 MW of generation was analyzed using the generator models employed for the Salton Sea #6 (geothermal plan) System Impact Study (200 MW each). These models will have to be verified with updated models as part of the Salton Sea #6 interconnection requirements. But for the purposes of this feasibility analysis, the modeling for the additional resources was proven adequate and acceptable.

Appendix C.2 lists the specific transient stability faults that were conducted for this analysis.

Key findings of the stability analysis included:

- The IID transmission system alternatives were found to be effective and stable under the conditions and faults taken for this analysis.
- The most critical single contingencies were found to be the loss of Devers-Valley 500 kV line or the Imperial Valley-Miguel 500 kV line. These results were consistent with the power flow (thermal) analysis.
- The lowest transient voltage (first swing voltage dip) was noted at the SCE Vista 230 kV bus for loss of the Devers-Valley 500 kV line.
- The addition of the Serrano/Valley to San Diego North 500 kV line was found to reduce the magnitude of the voltage dip at Vista 230 kV by providing an alternate source to Valley for loss of the Devers-Valley 500 kV line.

3.4 Post-Transient Analysis

The IVSG performed a Post-Transient analysis on the cases listed below, using the Reactive Power Margin Requirement criteria under the WECC Guidelines (NERC/WECC Planning Standards, I.D. WECC-G2) as a proxy for the WECC Standards I.D. WECC-S1, S2 and S3. In other words, this study was not performed using the WECC method of the increasing load or import by 105% or 102.5% (depending upon contingency) and then if the case solves, using that as proof of Post-Transient stability. Rather, this study was performed using the Reactive Power Margin Requirement (also know as V-Q Methodology developed by the Technical Studies Subcommittee of the WECC). The Reactive Power Margin Requirement provides a clearer, more accurate and definitive means to compare alternatives.

Appendix D.1 lists the study assumptions for the post-transient analysis, the contingencies run, buses monitored and the reactive margin criteria applied. Appendix D.2 shows the Q-V curves for critical contingencies; Appendix D.3, the tables of reactive margin values.

Cases Analyzed

The Post-Transient analysis was performed on seven cases: two Benchmark cases and five scenario cases using the GE PSLF Version 13.1 program. The benchmark cases represent Heavy Summer 2014 and Light Autumn 2014. There are two Heavy Summer alternative cases and three Light Autumn alternative cases. These seven cases were as follows:

1) Heavy Summer Benchmark (ivsg_hs_rev4)
2) HS, Imperial Valley – Central, Dispatch 1 (ivsg_hs_alt2d1_s1)
3) HS, Imperial Valley – Northern – Ser/Val, Dispatch 1 (ivsg_hs_alt3bd1_s1)
4) Light Autumn Benchmark (ivsg_la_rev5)

5) LA, Imperial Valley – Central, Dispatch 3 (ivsg_la_alt2d3_s1)
6) LA, Imperial Valley – Central & Coachella Valley – Indian Hills, Dispatch 3 (ivsg_la_alt2ad3_s1)
7) LA, Imperial Valley – Northern – Ser/Val, Dispatch 3 (ivsg_la_alt3bd3_s1)

Eighteen contingencies were run for this analysis, two of which did not apply to the two Benchmark cases. These included twelve single and six double contingencies.

In the analysis, 25 buses were monitored, including nine buses in SCE, seven buses in SDG&E, four in IID, four in CFE and one in MWD.

The Reactive Margin Criteria used in this study for SCE, SDG&E, CFE and IID was as follows: SCE - 300 MVAR (single element outage) and 150 MVAR (double element outage); SDG&E - 150 MVAR (single element outage) and 75 MVAR (double element outage); CFE - 100 MVAR (single element outage) and 50 MVAR (double element outage); IID - 100 MVAR (single element outage) and 50 MVAR (double element outage). It should be noted that the Reactive Margin Criteria used in this study are applicable only to this study and that they do not necessarily represent any utility's standard or policy.

This Post-Transient analysis considered the period of time after the power and voltage transient oscillations have damped out and before operator intervention can take place. This time frame is approximately one and half (1.5) to three (3) minutes subsequent to a disturbance.

Post-Transient Results

This analysis resulted in approximately 2,928 reactive margin values. Some of these reactive margin values are shown as Q-V curves which were produced for the most critical contingency for each case, with a representative assortment of buses included.

The most critical single contingencies were Imperial Valley – Miguel 500 kV and Devers – Valley 500 kV. Note the shift from the historic critical single contingency of Palo Verde – Devers to Devers – Valley 500 kV with the addition of Palo Verde – Devers #2. The most critical double contingency is the loss of Palo Verde – Devers 500 kV #1 and #2.[11]

The reactive margin values contained in the tables include shunt capacitor additions as indicated in the footnotes of the tables in Appendix D.1.3. With these additions, all buses met, or in most cases exceeded, the Reactive Margin Criteria. There is insufficient differentiation among margins, cases or seasons to strongly support one alternative over another.

In most cases, the shunt capacitor additions ranged from 150 MVAR to about 400 MVAR of increased reactive margin. Some of these additions will likely be part of other projects in the area, including the Sunrise Powerlink. The exception to needing no more than about 400 MVAR were some of the Light Autumn alternatives for the double contingency of Palo

[11] Note that the eastern termination of the Palo Verde – Devers #2 line is at Harquahala, not Palo Verde.

Verde – Devers 500 kV #1 and #2, which required as much as 1870 MVAR. However, this does not represent the real amount of reactive additions that would be required, as this Post-Transient study did not include the load dropping and/or other Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) which will be associated with this double contingency.

3.5 Production Cost Simulations

At the request of the IVSG, the CAISO performed production cost simulations to estimate the economic and physical performance of three final transmission configurations (Alternatives 2, 2a and 3b, as described in Section 3.2.5). The production cost simulation tool creates an economic generation dispatch that minimizes the total hourly production cost for the entire WECC transmission system, subject to generation, transmission and operational constraints. The output of the production simulation tool is processed to estimate the comparative production cost, loss and congestion savings of each of the alternatives. These results are useful in evaluating the viability of the transmission alternatives.

This study looked at comparative savings in WECC production cost, power losses and congestion hours due to the transmission projects. Other potential benefits such as market power mitigation, reduction in reliability-must-run generation cost, reduction in emissions and increased operational flexibility were not analyzed.

Study Description

The SSG-WI 2008 base case[12] was used as starting case. This base case includes generation and transmission infrastructure which are likely to be in place by 2008. The SSG-WI base case was updated to reflect forecasted 2010 load conditions in the study area (IID, SCE, SDG&E, CFE, LADWP and Arizona). New transmission and generation projects that are approved and planned to be online by 2010 in the Southwest area were modeled. These projects include:

- Harquahala-Devers 500 kV line
- New 500 kV Substation to be located at the Midpoint of Palo Verde-Devers and Harquahala-Devers 500 kV lines
- Blythe I and II Combined Cycle plant (1,000 MW) connecting to Midpoint Substation
- Reconductoring of four West of Devers 230 kV lines
- Four new simple cycle plants at CFE (340 MW)

The Benchmark base case used for the study modeled all the above projects. The project cases (Alternative 2, 2a and 3b) modeled the individual projects in addition to the 2,200 MW geothermal generation units. The geothermal units were considered to be base-load generators with must-run status. Startup/shut down cost, operation and maintenance costs, force outage rate and outage duration were modeled using typical values.

[12] SSG-WI, the Seams Steering Group-Western Interconnection, coordinates transmission expansion planning across the WECC. The base case was developed by the SSG-WI Planning Work Group.

The following transmission facility assumptions were simulated as part of the study.

- All WECC transmission paths were modeled according to 2005 Path rating catalog
- Limits for all 500 kV transmission facilities were enforced.
- Lower voltage (230 kV and below) limits were not enforced.
- SDG&E Simultaneous import limit was not enforced.
- SCIT limit was modeled at 17900 MW
- EOR limit was modeled at 9255 MW
- WOR limit was modeled at 11318 MW
- Path 42 (IID-SCE) was limited to 600 MW in the benchmark case and 1600 MW in the project cases
- All AC transmission lines monitored were limited to 95% of their thermal capacity or applicable rating in order to accommodate reactive flows which are absent in this production simulation studies.
- Nomograms were used to reflect transmission system constraints.
- Transmission losses were modeled.
- Transmission line/Path limit violation penalty of $1000 per MWh was applied.

Production Cost optimization runs were performed using production cost tool to predict both the economic and physical performance of entire WECC transmission network with and without the projects on an hourly basis for 2010.

Sensitivity Studies

A sensitivity study was run to evaluate the addition of 2,200 MW of geothermal generation to the Benchmark case without any new or upgraded transmission facilities (Benchmark-Sensitivity). This study was designed to quantify the proportion of the 2,200 MW of geothermal power that could be delivered without transmission upgrade, and the corresponding economic and physical performance of the system. This study assumed all the transmission facility limitations modeled in the Benchmark case. The limits for all 230 kV transmission lines in the IID area were also enforced.

In addition, a sensitivity on IVSG Project Alternative 2 was performed. This sensitivity case evaluates the economic and physical performance of extending the Imperial Valley-San Diego Central 500 kV line to the midpoint of the Valley-Serrano 500 kV line.

Production Cost Tool

The IVSG production cost simulation study was conducted using ABB's Gridview, which simulates the electricity market under realistic transmission system constraints, in hourly intervals. It incorporates a detailed supply model, demand model and a transmission system model. It uses an optimization algorithm that tries to dispatch generation resources such that the total production cost is minimized. The dispatch algorithm matches generation to hourly load and losses while taking into consideration transmission and operational constraints. Gridview program input data includes:

- Generation data, including capacity, fuel costs, heat rates, maintenance schedules, start-up/shut-down cost, up time, down time, forced outage rates and outage durations.
- Transmission data, such as network topology, thermal limits and operational constraints.
- Hourly demand data and distribution.
- Hourly hydro and wind dispatch.

Simulation outputs includes hourly dispatch for each generation unit, hourly production cost, hourly transmission line flows and Locational Marginal Prices at each WECC node.

Study Results

The simulation produced successful hourly production runs with sufficient generation resources to meet hourly demand and transmission losses subject to transmission and operational constraints for the benchmark and the project cases studied. Various transmission lines and interfaces were found congested for time periods ranging from one hour to several hours for all the cases studied. Appendix D.2.3 displays annual flow duration curves for major transmission lines and interfaces for all the cases studied.

WECC Annual Production Cost in the table below represents the total variable cost of generation for the entire WECC, before the new Imperial Valley generation is added (in the Benchmark cases), and after the 2,200 MW of renewable output is added in the other cases. Other key study results are the total hours of congestion on transmission interfaces and lines, and the total annual losses (MWh) on the transmission system. Table 3.2 provides a summary of the study results.

Table 3.2 Summary of Production Simulation Study Results

Study Cases	WECC Annual Production Cost (M$)	Total transmission Congested hours (hrs)	Total transmission losses (MWh)
Benchmark	15,731.35	146,206	34,687,733
Benchmark (Sensitivity)	15,471.24	172,887	33,863,293
Project Alternative 2	15,207.04	142,546	35,643,109
Project Alternative 2 (Sensitivity)	15,197.79	141,123	35,602,670
Project Alternative 2a	15,194.96	143,264	35,433,995
Project Alternative 3b	15,198.16	140,378	35,649,818

These study results indicate that Project Alternative 2a provides marginally greater savings in production cost and transmission losses. Looking at the congestion data, Project Alternative 3b provides a network that is least congested.

The sensitivity study results show that out of the 2,200 MW of geothermal units modeled in the Benchmark-Sensitivity case, only 800 MW could be delivered without new transmission facility additions. The hourly output profile of the geothermal units modeled in this sensitivity case is shown in Appendix D.2.2. The geothermal output might be substantially further reduced if transmission outage constraints were modeled. The results show that transmission congestion increased tremendously when new generation is added without transmission upgrades. Savings were nonetheless recorded in annual production cost and transmission losses with the geothermal units modeled. These savings might be eroded, however, if transmission outage constraints are included.

Project Alternative 2-Sensitivity study results showed a marginal saving in production cost, hours of congestion and transmission losses when compared to Project Alternative 2.

These production cost simulation study results, the results of the power flow and stability studies, and the cost of implementing the individual projects will all influence the choice of upgrade ultimately selected.

It is important to note that, as discussed in Chapter 2.4, this production cost simulation study was geared solely for comparing transmission alternatives. These study results do not provide an adequate basis for making investment decisions.

3.6 Further Study of Development Phases 1-3

The combination of thermal analysis, stability and post-transient analysis and production cost simulations established that each of the final alternatives were capable of exporting 2,200 MW of new Imperial Valley generation. The next task was to develop a plan for phasing this development. Three phases to accommodate the resource development were identified.

Phase 1: Transmission capability to export 645 MW of renewable resources by 2010.
Phase 2: Addition of 645 MW (1,290 MW of total development) by 2016.
Phase 3: Addition of 910 MW (2,200 MW of total development) by 2020.

Diagrams of the transmission upgrades in each phase are found on Figures 2.1- 2.3 in Chapter 2.

The phasing analysis is based on a conceptual build and delivery of the renewable resources to markets. The first phase assumes that the transmission must be capable of exporting 645 MW of new renewable resource development from the Imperial Valley by 2010. IID identified two alternative routings for Phase 1:

- Alternative A, for power flows from the Salton Sea geothermal field to the north: upgrades to Path 42,[13] increasing the export capability of that path by 1,000 MW (from 600 MW to 1,600 MW of total transfer capability). A diagram showing Alternative A is included in Figure 3.9 below.

- Alternative B, for power flows from the Salton Sea geothermal field to the south and west: upgrades of the existing lines from Highline substation to El Centro to Imperial Valley substation, increasing the total transfer capability in that path to 1,600 MW. Alternative B is represented on the diagrams of Phases 1-2, on Figures 2.1 and 2.2 in Chapter 2.

The Technical Work Group conducted power flow studies to evaluate the performance of Alternatives A and B with 645 MW of generation added in Phase 1; 1,290 MW added with Phase 2; and 2,200 MW added with Phase 3. Phase 1 was studied with forecasted 2010 loads for the IID, SCE and SDG&E planning areas; Phase 2 was studied with those loads increased by 11%, to approximate 2016 load levels.

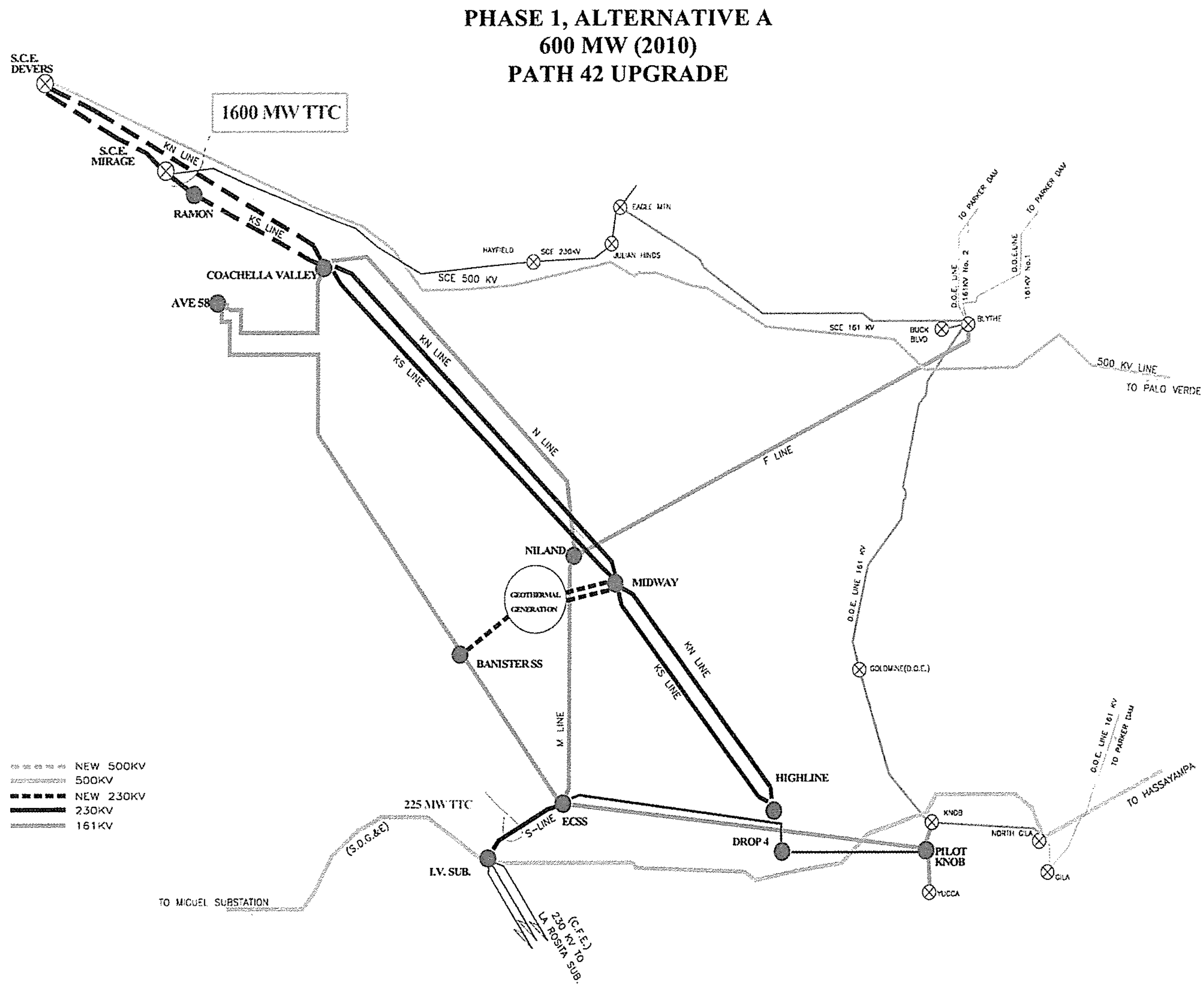
Alternative A would schedule new Imperial Valley flows across Path 42 to the CAISO at the SCE Devers substation. The IVSG study shows that additional transfers through Devers to the west would be problematic. More than 5,000 MW of new generation, located in both Arizona and California is expected to flow to Devers; much of this is already in the SCE interconnection queue. SCE is developing a West of Devers upgrade plan. The SCE system cannot accept 645 MW (Phase 1) at Devers Substation from the Imperial Valley. Doing so would require further, large-scale upgrades of the SCE system in that region, such as a 500 kV tie from Devers to Valley, in addition to SCE's current upgrade plan. An export plan that relied on making Imperial Valley generation deliverable through Devers accordingly would risk delaying Imperial Valley development until a regional plan for resolving west of Devers issues is identified and approved.

Utilization of the routing in Alternative B, by contrast, would minimize Imperial Valley flows at Devers. TWG studies show that Alternative B accommodates the export of at least 645 MW in Phase 1, with cost-effective upgrades of existing IID lines in that routing. Alternative B requires the Imperial Valley – San Diego 500 kV line to be in service.

For Phase 2, TWG studies show that getting the 1,290 MW to flow to San Diego County rather than to Devers requires connecting the incremental Imperial Valley generation directly to the west side of the IID system, at its Bannister substation, and with a new 230 kV line from Bannister to a new San Felipe substation that could interconnect to the proposed 500 kV line into San Diego. Phase 2/Alternative B further requires that the existing El Centro – Bannister 161 kV be upgraded to 230 kV.

[13] The IID Coachella-Ramon 230 kV line currently overloads with the loss of the Coachella-Mirage 230 kV line. As a result, action to correct this condition should be considered a pre-project upgrade (i.e., before Phase 1) since it is required to serve Coachella Valley load rather than for the export of renewable generation from the Imperial Valley.

Figure 3.9 Phase 1, Alternative A



For Phase 3, further upgrade of the (Alternative B) Highline-El Centro-IV path, in addition to the Phase 2 Bannister-San Felipe tie and the 500 kV line into San Diego County, accommodates 2,200 MW of export. TWG studies show that with this amount of generation connected to the IID system, unintended flow across Path 42 could be in the range of 200 MW, thus requiring upgrades of that path.

After evaluating the study results of Phases 1-3, the TWG and the Steering Committee both concluded that the IVSG development plan should be based on Alternative B. This will minimize flows to Devers, thus avoiding the uncertainty, potential delays and high cost of that routing and instead, work to maximize utilization of the proposed 500 kV line into San Diego County.

3.7 Limitations of this Plan; Further Studies Necessary

The recommended development plan presented in this report is based on conceptual studies. It presents a general framework for expanding transmission capacity in the region but does not contain sufficient detail to evaluate the connection of specific generating projects.

Some of the conceptual studies themselves also had limitations. In the SCE planning area, the power flow studies performed for heavy load conditions were stressed differently than those for light load conditions. As a result, not all of the same generating units were modeled as being on line in the Heavy Summer as in the Light Autumn cases.

The IVSG development recommendation does not constitute a plan of service for the interconnection of any specific generating projects. IVSG studies did not address all the impacts of the proposed generation and transmission alternatives on the existing transmission system. System Impact Studies and Facilities Studies will be required when individual generating projects request interconnection to the IID system. These detailed load flow, short circuit, stability and post-transient studies must be done on a regional basis; they must address how to mitigate any potential system problems so that system reliability is maintained and the plan of service is demonstrated capable of meeting CAISO/WECC/NERC reliability standards. Interconnecting generators planning to sell power into CAISO grid must submit a detailed TO Tariff application to the CAISO based on CAISO Tariff. Generators must also apply under IID's OATT for transmission service to the point of interconnection with the ISO. In addition, WECC path rating studies will be required for the IV to San Diego 500kV line and for any other WECC path (such as Path 42) whose rating must be increased.

The IVSG did not undertake a full economic evaluation of the proposed generation-transmission development. Such an evaluation, using the TEAM or equivalent methodology, will be necessary to support approval of the significant financial investment required to implement this plan. SDG&E's economic evaluation of the Sunrise Powerlink will include substantial export flows of renewable generation from the Imperial Valley. If this SDG&E evaluation does not provide enough information about the potential benefits and costs of the IVSG development, then an additional economic evaluation should be scheduled, to coincide with the application to interconnect the first major increment of new Imperial Valley generation.

Most significantly, the IVSG did not consider a tie between the IID and LADWP systems, as this was not proposed by those parties until IVSG transmission planning had been completed. A 500/230 kV tie, as proposed at the Indian Hills substation, could alter the size, structure and timing of the development phases recommended in this plan. LADWP and IID have performed some studies of this link; additional power flow and other studies will be required to determine the effect of this connection on regional facilities, including the flow of new generation connected to the IID system.

4.0 Permitting and Approval Plan

The Permitting Work Group (PWG) met periodically over seven months to develop a plan for coordinating and expediting the environmental studies and permit approvals required for all phases of the planned Imperial Valley renewables/transmission development. Participants included SDG&E, SCE, CalEnergy, non-jurisdictional utilities IID and LADWP, US Bureau of Land Management (BLM), CPUC, California Department of Parks and Recreation ("State Parks"), and other interested groups such as the Sierra Club and Border Power Working Group. The PWG identified the coordination of environmental review and the length of time for CPUC and CEC permit approval as key concerns to be addressed.

4.1 Environmental Review Documents: CEQA/NEPA

The PWG first explored the potential to develop one master environmental document to address both the regional benefits and the impacts of exporting renewable energy from the Imperial Valley. As the three development phases became better defined, it became apparent that the environmental documents would need to analyze the impacts of the project along the same time frames as proposed in those phases.

The IVSG anticipates Phase 1 in 2010, and Phase 3 in 2020. This span of over 12 years raised concerns about surveys becoming stale and findings that might not adequately review the environmental affects of the upgrades at the time they would be constructed. Meanwhile, much of the proposed transmission would provide other benefits to the individual utilities in addition to access to renewables. If each entity just analyzed its own separate component of a larger transmission plan, there might be concerns that the effects of the project were not analyzed as a whole but divided into smaller components to avoid finding significant impacts. The PWG also grappled with who should be the lead agency for this high-level environmental review document, given the involvement of both jurisdictional and non-jurisdictional utilities.

The PWG concluded that a programmatic approach provided the best vehicle to address all of the above concerns. The first step would be a broad, Programmatic EIR (P-EIR) that would take its project description from the development plan drafted by the IVSG. It would include at a high level:

- Impacts from the development of renewable resources in the Imperial Valley;
- Impacts from the upgrades of the IID system necessary to deliver geothermal/ renewable energy out of the IID control area;
- Impacts of a 500 kV line from Imperial Valley to San Felipe and on to San Diego;

- Impacts of a 500 kV line from the proposed Indian Hills substation to Upland, possibly including a connection to the IID Coachella Valley substation.

In the P-EIR, each of the above listed projects would have its own separate environmental documentation, and different lead agencies. By cooperating on the P-EIR, and sharing the study results for each utility's component of the project, the parties could save time and cost. This would allow future specific projects to tier off of the prior "big picture" environmental review. Also, the PWG agreed that the resource and permitting agencies should be brought into the planning effort on the programmatic document, in order to identify all areas of concern for detailed analysis in the follow-on documents. These agencies include the CEC, CPUC, California Department of Fish & Game, California Department of Parks and Recreation, U.S. Fish &Wildlife Service, U.S. Bureau of Land Management, and the Imperial County Planning and Development Services Department. The involvement of representatives of these agencies will help identify all impacts early and hopefully expedite the follow-on documents.

4.1.1 Agreement to Work Cooperatively

To compile a joint programmatic document that could be used for tiering purposes, the PWG recommends that IID, SDG&E, LADWP and CalEnergy enter into a Memorandum of Understanding for the sharing of costs for the P-EIR and the work of writing the descriptions of each entity's development plans. IID, LADWP, and SDG&E have already begun the independent environmental planning and study work for their portions of the project. Ideally, the programmatic review would be conducted and the P-EIR approved prior to the more detailed environmental analysis for the individual project components.

Currently, CalEnergy is the only generator intending to participate in the P-EIR effort. Other renewable generators interested in using the programmatic document to expedite their permitting study work are welcome to join the MOU. Doing so can help insure that their projects are analyzed in the context of the overall generation/transmission development.

Resource agencies and permitting authorities will also be invited to participate in the P-EIR Working Group. They would not be parties to the MOU because they would not have cost responsibilities.

4.1.2 CEQA Lead Agency

The PWG recommends that IID act as the CEQA Lead Agency on the P-EIR. IID's discretionary action triggering CEQA would be the approval by its Board of Directors of the proposed construction of the IID Green Path transmission plan, as part of the utility's system reliability upgrades.

The group discussed having the CPUC participate in the planning process on the programmatic document, either on the steering group or as a responsible agency under CEQA . This might enable the CPUC to utilize the P-EIR as the Proponent's Environmental Assessment (PEA) required in the CPCN application process for jurisdictional utilities. If the CPUC would be willing to do this, it could reduce the normal processing time of a CPCN application by several months.

4.1.3 MOU/CEQA Cost

The PWG recommends that the costs of the Programmatic EIR be shared evenly among the MOU signatories. Details will be spelled out in the MOU. The costs to produce the document are estimated to be $300,000. Issues to be addressed in the MOU include:

- Composition and operational guidelines for the P-EIR Working Group
- Cost sharing
- Milestones
- Role Designations
- Responsible Parties

4.1.4 Timeline

The advantage of a P-EIR with follow-on tiers is that the high-level framework is analyzed first. Future specific projects can then rely on the prior environmental assessment. Because some permitting work has already begun, the PWG believes the P-EIR needs to be complete within six months of signing the MOU and hiring an environmental contractor. This would match up with the time frames given by IID, SDG&E, and LADWP for their documents:

- SDG&E has begun study and environmental work for the Sunrise Powerlink, with the goal of construction start in January 2008 and completion in 2010.
- LADWP has begun environmental work on a 500 kV line, with a target for construction start in January 2008 and completion in January 2010.
- IID has completed planning work for its ten-year transmission plan and Green Path, and is prepared to request a major work authorization to start environmental and permitting work in fall 2005, with construction targeted to begin in 2007.
- CalEnergy has said it can build a geothermal plant every two years, contingent on signed PPAs for those plants. Meeting the 645 MW target for Phase 1 geothermal development by 2010 would require construction to begin in 2008 at the latest, with all three plants built simultaneously.

4.2 Rights of Way

The U.S. Bureau of Land Management (BLM)—both the El Centro and Palm Desert Field Offices—were instrumental in the PWG. The BLM identified the existing Utility Corridors that have been designated in the California Desert Conservation Plan areas in Riverside and

Imperial Counties. The PWG investigated the feasibility of doing one NEPA document with the BLM to designate new utility corridors, in which utility Rights of Way could be granted for the project, but a consensus could not be reached. While the location of system upgrades to existing lines could be identified, all utilities had concerns about corridors being placed in their service territories which might allow other utilities to build within existing systems. In addition, those utilities still investigating routing alternatives were unable to identify potentially workable corridor locations precisely enough. Consequently, the PWG abandoned the idea of developing one NEPA document to amend the Desert Plan for the purpose of adding utility corridors. However, all the utilities will work to identify the location of necessary corridors so that such corridors can be presented in the P-EIR. The actual NEPA documents to amend the Desert Plan will have to be developed in conjunction with the EIRs or EAs for the second tier of Imperial Valley generation/transmission development.

4.3 Permitting and Approval Processes

PWG members who have gone through state regulatory approval and permitting processes have many suggestions of ways to help expedite and coordinate them. State and federal agency staffs have heavy workloads. One method of assisting them is to find ways to bring in consultants earlier in the process. Currently, it is only after a utility files a CPCN application that the CPUC can retain an environmental consultant for the proposed project. In addition, a mechanism to involve responsible agencies from the very beginning could help insure that the environmental review addresses all agency concerns, thus producing documents that all responsible agencies can quickly adopt.. Similarly, the public and all interested environmental/stakeholder groups should be invited to identify concerns to be addressed at the beginning of the environmental review process. This would help insure that all concerns are being addressed in a public and open manner. If the P-EIR sufficiently outlines the regional benefits of the entire renewable effort, identifies environmental areas of concern, and directs the necessary follow-up, the CPUC could utilize it or portions of it for the applicant's PEA.

The federal agencies, while being able to be reimbursed for staff time, can only get involved when an applicant requests a permit or ROW. The PWG greatly appreciates the assistance of the El Centro and Palm Desert Field Offices of the BLM. They recommended that the utilities map out the necessary ROWs for all the phases and accomplish the Desert Plan amendments now, in anticipation of the need for the ROW, instead of doing separate NEPA documents and amendments for each phase. This is another way to cut down on regulatory agency staff work and time in order to speed up the process.

The Imperial County Planning and Development Services Department is in the midst of revising the Geothermal and Transmission Element in the County's General Plan. Their participation in the process enabled the PWG to understand the County's concerns. It highlighted the need for the utilities to comment on the Geothermal and Transmission Element, in order to assist the County in updating the plan based on the current geothermal information being studied. Cooperative efforts such as this also help expedite the permitting process between the utilities and local agencies.

State Parks provided invaluable insight into the ROW through the park system and helped direct the planning efforts to look more effectively for routes through protected areas. The PWG recommends that State Parks be a participant in the planning effort for the P-EIR. Reluctance to further open park land for new utility corridors makes it a priority to utilize existing State Park ROW for the necessary upgrades.

4.4 Policy Recommendations

The IVSG Steering Committee discussed the following options for expediting permitting and project approvals processes:

CPUC:

- Request the CPUC to amend General Order 131-D to eliminate the current duplication of environmental study efforts, so that only one environmental report is required (rather than one produced by an applicant and one by the CPUC).

- Request the CPUC to employ on-call contracts for its environmental consultants.

- In the absence of on-call contracting ability, request the CPUC to hire its environmental consultant before the IOU files its CPCN application (or at the time the applicant files the purpose and need portion of the CPCN application).

- Allow the state Lead Agency to assign an environmental consultant to work with the utility's (or applicant's) environmental consultant concurrently. This would enable the state Lead Agency's environmental consultant to be involved during a project's route selection, to help shape the PEA during the final four to six months of its development so that it can quickly be converted into an EIR. This option promotes earlier resource agency involvement.

CEC:

- Use CEC public review of the IVSG report (e.g., in the IEPR proceeding) to be counted as one of the public meetings necessary in the CEC plant-siting approval process. This could save one month or more in this approval process.

- The CEC plant-siting process requires investigating alternative lines/connections. IVSG transmission studies, which have been rigorously conducted by expert stakeholders, should help expedite the CEC's investigation of such alternatives.

- Power Plant Permitting: In the case of Imperial Valley renewable resources, transfer licensing authority and CEQA responsibilities from the CEC to Imperial County.

Permitting Salton Sea Unit 6 required 15 months from the time the CEC found the Application for Certification (AFC) to be "data adequate" in September 2002 to the formal approval of the AFC in December 2003.[14] By contrast, CalEnergy's 49 MW Salton Sea Unit 5 was permitted by Imperial County in less than four months. Imperial County has approved a resolution authorizing its Planning and Building Department to obtain siting authority from the CEC for plants up to 200 megawatts. The County believes that its 35 years of experience in processing geothermal plant permits, in combination with appropriate land use ordinances mandated in its General Plan gives it the expertise to satisfy CEQA requirements and other concerns.[15]

Federal:

- Expedite the environmental review for transmission projects in designated utility corridors once they are established. This involves the consideration of contingent corridors that would be evaluated at a programmatic level, and then elevated to 'designated' status upon a more detailed review at a project level.

4.5 Next Steps

The PWG effort enabled all participants to better understand the regulatory approvals needed for the development of geothermal and other renewables in Imperial County. The major parties intend to negotiate an MOU for the joint production of a P-EIR. They will also establish a meeting schedule to insure coordinated review of the environmental documents to be produced in the next year for the tiers of the project. By continuing to meet and share study information, the environmental contractors will be better able to adequately address the cumulative effects in each phase, and avoid overwhelming the government staffs that must review the documentation.

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[14] It should be noted that Salton Sea Unit 6 was the first geothermal power plant to be permitted by the CEC in more than 15 years. It is reasonable to assume that the staff's "learning curve" associated with this permitting effort significantly lengthened the overall permitting process.

[15] The Imperial County General Plan contains a "Geothermal Element" that was developed to provide guidelines for permitting geothermal energy plants. Imperial County has used those guidelines to permit more than 14 plants. In conjunction with the Geothermal Element, Imperial County also prepared a Master Environmental Impact Report for the Salton Sea KGRA. That EIR is updated regularly.

5.0 Tariff and Funding Issues

The IVSG development plan includes these major components: 1) network upgrades of the IID system; 2) the proposed 500 kV line into San Diego County; 3) in Phase 3, upgrades of the SCE Mirage–Devers tie and associated facilities on Path 42; and potentially, 4) a 500/230 kV connection between IID and LADWP.

IID and LADWP operate their own control areas, separate from the CAISO. The CPUC and FERC do not have jurisdiction over them. Both SDG&E and SCE are members of the CAISO, and fall under the jurisdiction of both the CPUC and FERC.

Renewable generators in the Imperial Valley will likely connect to the IID system, not the CAISO grid, even though much of their output is intended to be delivered to purchasers across the CAISO system.[16] They will thus be required to comply with the IID OATT and its corresponding interconnection procedures.

The proposed SDG&E 500 kV line into San Diego County is by definition a CAISO network upgrade, needed for both reliability and economic reasons. Upgrades of the SCE system on Path 42 triggered by inadvertent flow would likely be considered an economically driven project to reduce congestion costs. Many components of the IID build-out will be considered network upgrades of that system; other IID (and LADWP) upgrades may be considered the cost responsibility of interconnecting generators, in whole or in part. Cost allocation is a critical issue, and these realities make the allocation of the costs of the required upgrades complex.

CAISO tariff provisions allow the cost of network upgrades of its system to be spread broadly, across all users of the ISO grid. Upgrades of the IID (and LADWP) systems cannot be spread as broadly. Generators interconnecting to the IID/LADWP systems may be required to bear some portion of the cost of the upgrades required to make their output deliverable to the CAISO grid. The amount of this generator cost responsibility will greatly affect the ability of geothermal and solar developers to sell their power. High wheeling charges could limit renewable development for export. Resolution of these issues remains a priority for IVSG parties. Some of the considerations involved are discussed in this chapter.

Transmission Cost Responsibility

Imperial Valley generators will bear the cost of building transmission ("gen-ties") from their projects to connect to the IID (or SDG&E) systems.

Some of the transmission upgrades on the IID system are required for the primary purpose of delivering geothermal energy to neighboring utilities. However, there are collateral benefits to IID's system as the overall capability and reliability of the IID transmission system will be

[16] The 300 MW solar project whose output will be purchased by SDG&E under a recently announced contract may connect directly to the CAISO grid.

enhanced by the identified upgrades. The majority of upgrades associated with geothermal development near the Salton Sea are anticipated to be network upgrades. IID would fund such upgrades and recover the cost through charges for transmission service across its system.

Some of the network upgrades may also be part of IID's grid assessment plan. To accommodate renewable resource development, some of these upgrades may need to be accelerated, on the schedule anticipated by the IVSG development plan. Interconnecting generators would in such cases pay the cost of completing the upgrade sooner than it would be required for load-serving or reliability reasons.

The SDG&E 500 kV line will likely be considered a network upgrade. Under the CAISO tariff, the cost of this upgrade will be spread among all users of the CAISO grid.

Cost Recovery

IID has stated it will secure financing either internally or from third party sources to complete its transmission system upgrades. IID's capital costs will be rolled into its rate base for transmission service across its grid. IID will obtain cost recovery through its OATT from generators connecting to its system through interconnection requests and transmission service requests.

The SDG&E 500 kV line in San Diego County and associated facilities is an essential component of the IVSG plan to export renewable resources, beginning in Phase 1. In Phase 3, upgrades of Path 42 on the SCE system may also be required, even though no Imperial Valley generation has been scheduled to SCE at its Devers substation. As mentioned above, these upgrades may be justified on reliability and economic grounds. To the extent that they are needed to comply with the state RPS mandate, special consideration by the CPUC and CAISO is indicated.

FERC must ultimately approve the SDG&E and SCE facilities as eligible for cost recovery in transmission rates. To ensure against possible disallowance at FERC, the State of California and the CPUC must establish an alternative mechanism, consistent with the Federal Power Act, to provide cost recovery certainty for the IOUs in order for this plan to be realized. To this end, the CPUC must find in the respective CPCN orders that the jurisdictional facilities discussed in this plan provide network benefits and take all other steps required under Public Utilities Code Sec. 399.25

In the CAISO, the cost of network upgrades is spread among all users of the grid. The cost of IID upgrades cannot be spread as widely. The IVSG Steering Committee fully understands that the development of renewable resources in the region is contingent on the ability of generators to sell their power at competitive rates, and that transmission service charges paid by renewable generators is a key component of that ability.

Operational Control

IID intends to own and operate all transmission facilities in its service territory.

SDG&E and SCE are Participating Transmission Owners (PTOs) of the grid operated by the CAISO. Any portion of a transmission upgrade, interconnection facilities, and associated facilities forming part of a PTO's transmission network will be transferred to CAISO operational control pursuant to the Transmission Control Agreement among the CAISO and PTOs.

Financing Options

During the course of the IVSG effort, IID determined that it would fund its system upgrades itself, either through bonding or third party financing options. In regards to the proposed 500 kV transmission line, interested parties could pursue transmission ownership contracts, such as the SDG&E-IID California Project Participation Agreement. In this model, each party's ownership share would be negotiated between the parties to be proportional to the amount of transmission capacity they had requested; each would bear a commensurate share of the construction costs. PTOs who transfer operational control of their transmission system to the CAISO could maintain the use of the transmission so financed, consistent with their PTO agreements with the CAISO.

The CAISO can direct its PTOs (in this case, SDG&E and SCE) to fund upgrades of their systems, and allow for recovery through the CAISO's High Voltage Access Charge. The CAISO may be able to direct such an action based on the need of its PTOs to meet state RPS goals.

6.0 Follow-On Work

The IVSG has provided a mechanism for key stakeholders to jointly create a planning framework for a complex, regional inter-utility, inter-control area development project. The agreement of IID, SDG&E, LADWP and CalEnergy to jointly produce a P-EIR addressing the overall generation-transmission development is one valuable outcome of the IVSG effort. Collaborative electrical planning among utilities is another. The parties should extend this cooperation to the next stages of work required to implement the proposed development.

6.1 Imperial Valley Implementation Group

This work includes transmission studies of the proposed IID-LADWP tie, and its effect on exports of Imperial Valley generation to CAISO (and other) delivery points. This connection, and the size of DWP acquisitions of Imperial Valley renewables, may require the size, timing and structure of the development phases recommended here to be reconfigured. Agreements among IID, LADWP and SDG&E as to the ownership and construction of proposed upgrades may also affect the structure and sequence of the overall development.

After the phases are better defined, on the basis of this new information, an economic evaluation of the costs and benefits of the overall development may be necessary. Some cost responsibility and cost recovery issues also remain to be resolved. But the largest and most important implementation tasks are building the widespread public support necessary to overcome opposition to the construction of new facilities, and the winning of permit approvals. This work can be facilitated by continued collaboration. The key parties may be able to achieve their objectives more effectively by attaching them to the larger effort of developing and exporting Imperial Valley renewable resources.

Some of the work required for discrete transmission additions will be done by individual entities; all of the stakeholders will need to follow the WECC process for transmission additions having regional impacts. Continued cooperation in those arenas, as well as on-going bilateral negotiations between the parties concerning the commercial terms for participation in the 500 kV lines being proposed, will aid in moving this effort forward.

To this end, key stakeholders could transform the IVSG into a smaller Imperial Valley Implementation Group focused on permit approval and construction. This would provide a vehicle for collaborating on common tasks, for working out agreements on key issues, and for expediting all aspects of the joint generation-transmission development. An IV Implementation Group could establish goals and target dates for the overall development, and take responsibility for ensuring progress toward construction. It would report its progress quarterly, to stakeholders, the CPUC, CEC and Governor. The IVSG Steering Committee discussed forming such a working group, but could not reach agreement on whether to do so.

David B. Olsen

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Energy Development And Policy

David Olsen serves as convener of the Imperial Valley Study Group, a stakeholder planning collaborative working to develop solutions capable of exporting 2,200 MW of geothermal and solar power from California's Imperial Valley. IVSG members include: California Energy Commission, California Public Utilities Commission, Imperial Irrigation District, Los Angeles Department of Water and Power, San Diego Gas & Electric, Southern California Edison, Western Area Power Administration, environmental groups, state and federal agencies, and other interested parties. The work of the IVSG is described at: www.energy.ca.gov/ivsg.

He also serves on the steering committee of the Tehachapi Study Group, a similar stakeholder planning collaborative working to develop a plan for exporting 4,500 MW of wind power from California's Tehachapi Mountain region.

Earlier, Olsen led the development of solar, wind, hydro and geothermal power projects in more than 20 countries, as President of Clipper Windpower Development Company, President/CEO of Northern Power Systems, President of Peak Power Corp., Vice President of Magma Power Company, and director of International Utility Structures, Inc., a manufacturer active in more than 100 countries.

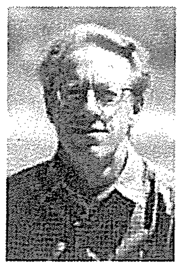
Olsen has been a director of the Center for Energy Efficiency and Renewable Technologies since 1991, and served as its Chair 1994-1996. He was a founding member of the Business Council for Sustainable Energy and has served on many power industry trade associations including the American Wind Energy Association, Independent Energy Producers, Geothermal Energy Association, National Hydropower Association, Nevada Geothermal Council, Northwest Electric Light & Power Association and the World Geothermal Congress.

In this work building the renewable energy industry, he has had oversight responsibility for research involving photovoltaic cells, batteries, low-temperature metallurgy, wind turbine aerodynamics, power electronics, management of super-saturated geothermal brines, and generation system modeling. He has served on the California Utility Research Council, and has raised money to fund this research from the U.S. Navy, U.S. DoE, the California Energy Commission, the Electric Power Research Institute and large manufacturing firms.

In 2000, Mr. Olsen led the creation of the California Climate Action Registry (http://www.climateregistry.org/), the first state registry of greenhouse gas emissions. He is actively involved in the development of policies to address climate change at the state and national level, leading meetings and workshops such as:

- "Procurement Incentive Framework for GHG Reduction," (R.04-04-003) California Public Utilities Commission, March 7-9, 2005.

- "Adapting to Higher Energy Cost and Carbon Constraints in the Mountain West," a Leadership Roundtable on Energy Efficiency. Wirth Chair, University of Colorado, Denver, September 27-28, 2004.
- "Registries and Trading as Climate Change Policy Approaches," Aspen Institute, Washington DC, March 8, 2004.
- Colorado Business Energy Partnership, monthly meetings of Colorado companies and cities working to monitor their greenhouse gas emissions and improve energy efficiency. 2000-2005.
- "National Leadership Forum on Energy Efficiency and Climate Change Policies," CEO Coalition to Advance Sustainable Technology, Washington, D.C., May 10, 2000.



David B. Olsen
Ventura, CA 93001
805-648-6196 fax
olsen@avenuecable.com
www.cleanpowercollaboration.com